CLAIMS

1. (Currently Amended) A[[n]] thermodynamic oil and gas recovery system [[for]] that may simultaneously inject[[ing]] thermodynamically treated fluids ~~compressed gases cooled by recovered liquids and liquids heated by the heat of compression of recovered gasses~~ into an oil and gas well for uninterrupted production from said well during well maintenance.

2. (Original) The recovery system in claim 1 wherein the frequency of lift gas injection is controlled by wellhead pressure.

3. (Currently Amended) A thermodynamic lift gas injection unit that may inject thermodynamically treated fluids for recovering oil and gas from a well controlled by wellhead gas pressure.

4. (Original) The unit in claim 3 wherein said lift is pulse lift.

5. (Currently Amended) A thermodynamic lift gas injection unit that may [[for]] simultaneously inject[[ing]] thermodynamically treated fluids into an oil and gas well without interrupting production.

6. (Currently Amended) A thermodynamic lift gas oil and gas recovery unit controlled by wellhead pressure that may [[for]] simultaneously inject~~ing compressed gasses cooled by recovered liquids and liquids heated by the heat of compression of recovered gasses~~ thermodynamically treated fluids into an oil and gas well for well maintenance without interrupting production.

7. (Currently Amended) The recovery unit in claim 6 wherein [[said]] the compressed gasses in said thermodynamically treated fluids are gasses recovered from a subterranean reservoir by said oil and gas well.

8. (Currently Amended) The recovery unit in claim 6 wherein [[said]] the liquids in said thermodynamically treated fluids ~~heated by the heat of compression of recovered gasses~~ are liquids recovered from a subterranean reservoir by said oil and gas well.

9. (Original) The recovery unit in claim 8 wherein said liquids may include saltwater.

10. (Original) The process of transferring heat generated by compressing gas to heat liquids and to cool gases being compressed, and injecting said liquids into an oil and gas well for well maintenance without interrupting the injection of cooled lift gas.

11. (Original) The process in claim 10 wherein said gas is natural gas recovered using said well, and the heated liquid injected into said well is crude oil recovered using said well, water, or a mixture thereof.

12. (Currently Amended) The process of simultaneously injecting ~~lift gas and heated liquids~~ thermodynamically treated fluids as lift gas and maintenance fluids for well maintenance into an oil and gas well ~~simultaneously~~.

13. (Currently Amended) The process in claim [[11]] 12 where said lift gas is natural gas recovered using said well, and said maintenance fluids may include ~~a heated liquid injected into said well is~~ crude oil recovered using said well, water, or a mixture thereof.

14. (Currently Amended) The combined processes of simultaneous well maintenance and oil and gas recovery from an oil and gas well ~~wherein~~ comprising

using a gas compressor with its ~~the~~ stroke frequencies ~~of a gas compressor are~~ controlled by the pressure of natural gas from said well to compress lift gasses,

transferring heat generated by said compressor ~~is transferred~~ to fluids ~~liquids~~ to be injected into said well, and

simultaneously injecting gas compressed by said compressor into said well with said fluids to lift liquids with or without heated liquids for well maintenance.

15. (New) The thermodynamic recovery system in claim 1 wherein said thermodynamically treated fluids are heated, cooled and/or used for said production and well maintenance that includes:

a compressing means that includes:

at least two compression cylinders capable of compressing and pumping gasses mixed with contained liquids,

at least one pump and

a power supply,

a power limit means for setting the volume displacements for each of said cylinders,

a reservoir containing liquids and natural gas,

said well,

an output means capable of injecting gasses compressed in said compressing means into said reservoir as lift gas, at least a portion of which may be recovered natural gas from said reservoir,

a separating means capable of separating said recovered natural gas and recovered liquids from said reservoir, and

an input means capable of transferring at least part of said recovered natural gas into said compressing means as input gas with the density of said input gas determined at least in part by the composition, temperature and pressure of said natural gas in said reservoir and the plunging action therein.

16. (New) The recovery system in claim 15 wherein said well includes:

a well head,

a casing extending from said well head into said liquids in said reservoir,

a lifting chamber enclosed in said casing extending from said well head into said liquids, and

an injection chamber enclosed in said lifting chamber extending from said well head into said liquids wherein said output means injects interment pulses of said lift gas through said well under the surface of said liquids in said reservoir and lifts at least a

portion of said liquids with large bubbles of said lift gas, thereby creating said plunging action when said bubbles of said lift gas are released into said liquid.

17. (New) The recovery system in claim 16 with an external thermodynamic exchange means for heating maintenance liquids, which may include said recovered liquids, and an injection means capable of injecting said maintenance liquids into said well for well maintenance and storing production fluids without interrupting production.

18. (New) The recovery system in claim 17 wherein said external thermodynamic exchange means is said compression means immersed in a separator.

19. (New) The recovery system in claim 16 wherein said density of said input gas influences the volumetric efficiency of each of said cylinders.

20. (New) The recovery system in claim 16 wherein the volumetric efficiencies of said cylinders determines the rate of injection of said lift gas and the size of said bubbles injected.

21. (New) The recovery system in claim 17 wherein said compressing means is a HEC and said lift gas and injection means are a BPU.

22. (New) The recovery system in claim 21 wherein said compressing means comprises a first compression chamber with a volumetric efficiency ranging up to at least 0.9328 and a second compression chamber with a volumetric efficiency ranging up to at least 0.9995.

23. (New) The recovery system in claim 15 wherein said liquids include saltwater.

24. (New) The thermodynamic injection unit in claim 3 wherein said thermodynamically treated fluids are heated, cooled and/or used for production and well maintenance that includes:

a compressor with at least two compression cylinders capable of compressing and pumping gasses mixed with liquids, and a switching device for limiting the volume displacements for each of said cylinders,

external and internal thermodynamic exchange means for cooling gasses during compression and heating liquids,

a separating means capable of separating recovered natural gas and recovered liquids,

an output means capable of injecting intermittent pulses of gasses compressed in said compressor into liquids in a subterranean reservoir as large bubbles of lift gas,

a lifting means capable of lifting said liquids with said large bubbles of said lift gas,

a recycling means capable of inputting at least part of said recovered natural gas into said compressor as input gas with the density of said input gas determined at least in part by the composition, temperature and pressure of natural gas in said reservoir and the plunging action therein, and

an injection means capable of injecting maintenance liquids, which may include said recovered liquids, for well maintenance without interrupting production.

25. (New) The injection unit in claim 24 wherein said compressor and said thermodynamic exchange means and said separating means are included in a HEC, and said output, lifting, injection, and recycling means are included in a BPU.

26. (New) The injection unit in claim 25 wherein said density of said input gas influences the volumetric efficiency of each of said cylinders.

27. (New) The injection unit in claim 26 wherein said volumetric efficiencies of said cylinders determines the rate of injection of said lift gas and the size of said bubbles injected.

28. (New) The injection unit in claim 25 wherein compression in said compressor, injection by said output means, and lifting by said lifting means adapt to changing amounts of natural gas available to said unit.

29. (New) The injection unit in claim 28 wherein said compressor and said injection and lifting means adapt by changing the size of said bubbles injected and rate of injection of said pulses.

30. (New) The injection unit in claim 29 capable of slowly injecting very large pulsed bubbles of compressed gas with a lifting capacity up to at least ten to fifty cubic feet of liquids from said reservoir per pulse at a frequency in the range of two to ten pulses per minute.

31. (New) The injection unit in claim 29 wherein said compression cylinders include a first compression chamber with a volumetric efficiency ranging up to at least 0.9328 and a second compression chamber with a volumetric efficiency ranging up to at least 0.9995.

32. (New) The process in claim 12 which also includes:

compressing gas in a compressor capable of pumping liquids and gas,

injecting at least a portion of said gas compressed in said compressor into a subterranean reservoir as lift gas,

recovering a mixture of liquids and natural gas from said reservoir,

separating said mixture,

storing said liquids and any excess of said natural gas, and

repeating the process by compressing said natural gas in said compressor as lift gas for the next injection.

33. (New) The process in claim 32 wherein said gas compressed in the first compressing step of the initial process is natural gas from said reservoir.

34. (New) The process in claim 32 wherein said lift gas is injected intermittently as large bubbles with plunging action.

35. (New) The process in claim 34 wherein recovery from said reservoir adapts to changing amounts of said natural gas by changing the size of said bubbles injected and the frequency at which said process repeats.

36. (New) The process in claim 34 wherein said compressor adapts to changing amounts of said natural gas by changing the size of said bubbles injected and the frequency at which said process repeats.

37. (New) The process in claim 34 wherein injection in said injection step adapts to changing amounts of said natural gas available from said reservoir by changing the size of said bubbles injected and the frequency at which said process repeats.

38. (New) The process in claim 34 wherein the frequency at which said process repeats is influenced by the density of said gasses compressed in said compressor and said plunging action.

39. (New) The process in claim 34 wherein a HEC is used for the compressing steps, a BPU is used for the injection steps, and heated maintenance liquids may be injected simultaneously with said lift gas.

40. (New) The process in claim 39 wherein said heated maintenance liquids may include water, said liquids, or a mixture thereof recovered from said reservoir.